UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

January 26, 2004

Tennessee Valley Authority
ATTN: Mr.J. A. Scalice
Chief Nuclear Officer and
Executive Vice President
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: SEQUOYAH NUCLEAR POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000327/2003006 AND 05000328/2003006

Dear Mr. Scalice:

On December 27, 2003, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Sequoyah Nuclear Power Plant, Units 1 and 2. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 7, 2004, with Mr. Rick Purcell and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the inspectors identified eight issues of very low safety significance (Green). Seven of these issues were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as non-cited violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny these non-cited violations, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Sequoyah facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/ADAMS.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Stephen J. Cahill, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket No.: 50-327, 50-328
License No.: DPR-77, DPR-79

Enclosure: Inspection Report 05000327/2003006 AND 05000328/2003006
w/Attachment: Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-327, 50-328
License Nos:	DPR-77, DPR-79
Report No:	05000327/2003006 and 05000328/2003006
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant
Location:	Sequoyah Access Road Soddy-Daisy, TN 37379
Dates:	September 28, 2003 - December 27, 2003
Inspectors:	S. Freeman, Senior Resident Inspector R. Telson, Resident Inspector R. Carrion, Project Engineer (Sections 4OA1, 4OA3.2) G. Hopper, Senior Reactor Inspector (Section 1R11) J. Blake, Senior Project Manager (Section 1R08) R. Chou, Reactor Inspector (Section 1R08)
Approved by:	S. Cahill, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000327/2003-006, IR 05000328/2003-006; 09/28/2003 - 12/27/2003; Sequoyah Nuclear Power Plant, Units 1 & 2; Fire Protection, Inservice Inspection Activities, Licensed Operator Requalification Program, Maintenance Risk Assessment and Emergent Work Evaluation, Refueling and Outage Activities, Event Followup.

The report covered a three-month period of inspection by resident inspectors and announced inspections by three region-based inspectors. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a non-cited violation of TS 4.0.5, Inservice Inspection Program, for an inadequate examination of a pipe support. This resulted in the failure to identify a 3/16-inch gap between the pipe bottom and the supporting structural steel member during the inservice visual inspection of the ASME Class 1 Safety-Related Chemical & Volume Control System Seal Water Injection Line to Unit 2 Reactor Coolant Pump #4 pipe support. A gap in this support would change the support function from functional to non-functional.

  This finding is more than minor because it was associated with the Initiating Events cornerstone and affected the objective of limiting the likelihood of events, such as a pipe break and support failure. Failure of the inspection program to identify a non-functional support, which would change the pipe stress analyses and the pipe support design, could lead to more significant problems if left uncorrected. The issue was determined to be of very low safety significance because it was found acceptable after the pipe stress analyses were re-performed with the gap condition and the new pipe support loads (Section 1R08).

- Green. The inspectors identified a non-cited violation of Technical Specification (TS) 6.8.1 for failure to comply with plant configuration control procedures. Both pressurizer power-operated-relief-valve block valves on both units were simultaneously closed without the use of an approved work document, resulting in a missed risk assessment.

  This finding is more than minor because it affected the configuration control attribute of the Initiating Events cornerstone. Alteration of safety related equipment configuration outside of approved processes would, if left uncorrected, result in a more significant safety concern. While not prohibited by TS, this action removed an over-pressure reactor trip barrier and would challenge the pressurizer safety valves in response to an over-pressure transient. This finding is of very low safety significance because closure of the block valves only affected the initiating event cornerstone and did not directly contribute to the likelihood of a primary system event initiator (Section 1R13).

- Green. The inspectors identified a finding for a self-revealing failure to follow the plant configuration control process on non-safety related equipment. An instrument isolation valve on the Unit 1 turbine front standard was inappropriately left closed following a refueling outage and resulted in a generator load rejection and reactor trip.

  This finding is more than minor because it affected the configuration control attribute of the initiating event cornerstone and challenged the ability of operators and the reactor protection system to safely shut down the plant. With the isolation valve to Pressure Switch 1-PS-47-76 inappropriately closed, a generator load rejection and subsequent reactor trip were assured when the turbine thrust bearing trip test was performed. This finding is of very low safety significance because no mitigating system was affected. The cause of the finding is related to the cross-cutting element of human performance (Section 4OA3).

Cornerstone: Mitigating Systems

- Green. The inspectors identified a non-cited violation of License Condition 2.C (13) for failure to implement and maintain all provisions of the approved fire protection program. The water supply to several hose stations inside the Unit 2 reactor building was isolated without implementing any compensatory measures as required by the fire protection program.

  This finding is more than minor because it left portions of the Unit 2 containment without manual fire suppression for 48 hours, a reduction of fire defense-in-depth. If left uncorrected this would affect the ability of the station to mitigate a containment fire. This finding is of very low safety significance because automatic suppression systems were not affected and operability of the impaired fire suppression equipment could be rapidly restored in the event of a fire (Section 1R05).

- Green. The inspectors identified a non-cited violation (NCV) for failure to certify qualifications and status of licensed operators were current and valid and that the requirements of 10 CFR 55.53, “Conditions of Licenses” for license reactivation were met prior to their resumption of license duties. Only four out of the thirteen selected operator reactivation records were available for inspection.

  The finding is greater than minor because it is associated with the Mitigating Systems Cornerstone human performance attribute that affects the availability, reliability, and capability of operators to respond to initiating events to prevent undesirable consequences that could pose a potential risk to operations. The finding was evaluated using the Operator Requalification Human Performance SDP and was determined to be a finding of very low safety significance because there was no evidence of an inactive operator standing a watch. Since more than 20% of the reactivation records had deficiencies in that they were not available and could not be verified to meet reactivation requirements, the issue was determined to be a green finding. (Section 1R11).

- Green. The inspectors identified a non-cited violation of 10 CFR, Part 50.65, Paragraph (a)(4), for the failure to properly manage risk when removing the Unit 1 B-Train components from service for a component cooling and essential raw cooling water header outage. Centrifugal Charging Pump 1B was inadvertently tagged out and made unavailable when it was not part of the scheduled maintenance plan. This put Unit 1 in a configuration different from that evaluated in the risk assessment and resulted in a situation not allowed by licensee site risk procedures.

  This finding is more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone and affected the availability of the charging pumps. It resulted in an unplanned 8.5 hour unavailability of the pump and an unplanned, unrecognized increase in risk. This finding is of very low safety significance because it did not represent an actual loss of safety function of a system nor did it represent an actual loss of safety function of a single train for greater than its technical specification-allowed outage time (Section 1R13).

- Green. The inspectors identified a non-cited violation of Technical Specification 6.8.1 for a self-revealing failure to comply with plant general operating procedures. While draining Unit 2 to mid-loop conditions, the licensee failed to open a head vent valve required by the draining procedure. This caused the level monitoring system to indicate a lower level than was actually present.

  This finding is more than minor because configuration control errors, while in reduced inventory or mid-loop conditions where safety margins are small, can result in a loss of decay heat removal capability. This finding is of very low safety significance because decay heat removal capability was not lost and the unit did not enter mid-loop conditions with the valve closed. The cause of the finding is related to the cross-cutting element of human performance (Section 1R20).

- Green. The inspectors identified a non-cited violation of Title 10 of the *Code of Federal Regulations*, Part 50, Appendix B, Criterion V, for failure to use an adequate procedure for freeze protection of the level instruments on the Unit 2 refueling water storage tank. The method of checking for proper operation of the heater in the instrument enclosures, checking for warmth by hand, was not capable of verifying sufficient current and thus could not detect any degradation or failure due to degraded cables and extreme cold. This resulted in two wide-range instruments failing due to freezing in extremely cold weather.

This finding is more than minor because, if left uncorrected, all four wide-range level instruments would have been affected. This finding is of very low safety significance because the safety function provided by the four instruments was not actually lost (Section 4OA3).

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and associated corrective actions are listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status:

Unit 1 operated at or near 100% rated thermal power (RTP) during the entire inspection period.

Unit 2 began the period at 100% RTP. On November 9, 2003, the unit was shutdown for a scheduled refueling outage. Outage activities were completed and the unit was taken critical on December 10, 2003. The unit returned to 100% RTP on December 15, 2003. On December 27, 2003, the unit was shutdown to repair a hydrogen leak on the main generator and remained shutdown at the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors reviewed design features and licensee preparations for protecting the essential raw cooling water (ERCW) intake structure and both Unit 1 and 2 refueling water storage tanks (RWSTs) from extreme cold and freezing conditions. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and Technical Specifications (TS), reviewed and observed implementation of licensee freeze protection procedures, and walked down portions of the systems to assess the status of system deficiencies and the system readiness for extreme cold weather. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

Partial System Walkdowns

The inspectors performed a partial walkdown of the following three systems to verify the operability of redundant or diverse systems and components and to identify any discrepancies that impacted the function of the system when safety equipment was inoperable. The inspectors reviewed applicable operating procedures, walked down control system components, and verified that identified problems were entered into the corrective action program. Additional documents reviewed are listed in the attachment.

- Emergency Boration Valve 2-62-138 during Maintenance on the Unit 2 Blender
- Unit 1 A-Train ECCS Components during Maintenance on B-train ESF and CCS Headers that Rendered B-train ECCS Components unavailable
- Unit 2 Motor-Driven Auxiliary Feedwater Trains during Check Valve Testing of Turbine Driven Auxiliary Feedwater (TDAFW) Pump 2A-S

Complete System Walkdown

The inspectors performed a complete system walkdown of the Unit 1 RHR System to verify proper equipment alignment and identify any discrepancies that could impact the function of the system and increase risk.

The inspectors reviewed the UFSAR, system procedures, system drawings, and system design documents to determine the correct lineup and then examined system components and their configuration to identify any discrepancies between the existing system equipment lineup and the correct lineup. In addition, the inspectors reviewed outstanding maintenance work requests and design issues on the system to determine whether any condition described in those work requests could adversely impact current system operability. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted a tour of the eight areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that combustibles and ignition sources were controlled in accordance with the licensee's administrative procedures; that fire detection and suppression equipment was available for use; that other passive fire barriers were maintained in good material condition; and that compensatory measures for out-of-service, degraded, or inoperable fire protection equipment were implemented in accordance with the licensee's fire plan. Documents reviewed are listed in the attachment.

- Emergency Diesel Generator Building
- Auxiliary Building Elevation 669 (Unit 2 Pipe Gallery)
- Control Building Elevation 706 (Cable Spreading Room)
- Essential Raw Cooling Water Building
- Auxiliary Building Elevation 690 (Unit 1 Pipe Chase)
- Auxiliary Building Elevation 653 (Unit 1 Pipe Chase)
- Control Building Elevation 734 (Relay Room)
- Control Building Elevation 734 (Auxiliary Control Room)

b. Findings

Introduction: The inspectors identified a green non-cited violation (NCV) for failure to implement and maintain in effect all provisions of the approved fire protection program.

Description: On September 6, 2003, fire protection personnel initiated Impairment Permit FOR2003A0391 and closed water supply shutoff valve 1-26-1242 to flow control valve 1-FCV-26-227, which services six hose stations in the vicinity of the reactor coolant pumps and lower containment air filters in the Unit 2 reactor building. The flow control valve had begun to leak by and was isolated pending replacement.

The impairment permit did not identify any compensatory measures even though it indicated they were required. It documented only that no fire watch was required and that the impaired fire hose stations were required to be returned to operable status within 14 days. The impairment permit was revised on September 8, 2003, to direct the manual re-opening of the shut water supply valve as the intended compensatory action in the event of a fire. However, the required compensatory action, per the Fire Protection Plan Limiting Condition for Operation (LCO) to route additional equivalent capacity fire hoses to the unprotected areas from an OPERABLE hose station within 24 hours, was not implemented until September 17, 2003. The inspectors determined that the September 8 revision, while identifying a compensatory measure, did not comply with the LCO-specified action to route fire hoses and that the compensatory measure was not implemented within the required 24-hours.

Analysis: This finding was more than minor because it left portions of the Unit 2 containment without manual fire suppression for 48 hours, a reduction of fire defense-in-depth. If left uncorrected this would affect the ability of the station to mitigate a containment fire. Using the Fire Protection Significance Determination Process (SDP) the inspectors determined the finding to be of very low safety significance (Green) because automatic suppression systems were not affected and operability of the impaired fire suppression equipment could be rapidly restored in the event of a fire.

Enforcement: License Condition 2.C.(13) states, in part, that the licensee shall implement all provisions of the approved fire protection program referenced in the UFSAR. USFSAR Paragraph 9.5.1, Fire Protection System, references the Fire Protection Report (FPR). FPR Part II - Fire Protection Plan, Revision 12, Chapter 14.5, Fire Hose Stations, Paragraph 3.7.11.4, Action a, states, in part, “With one or more of the fire hose stations... inoperable, route an additional equivalent capacity fire hose to the unprotected area(s) from an OPERABLE hose station within...twenty-four (24) hours.” Contrary to this, on September 6, 2003, with several Unit 2 reactor building hose stations inoperable, the licensee failed to route additional equivalent capacity fire hoses to the unprotected areas. Because this violation was determined to be of very low safety significance (Green), it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 05000328/2003006-01, Failure to Implement Timely and Appropriate Fire Protection Compensatory Measures. This violation is in the licensee’s corrective action program as PER 03-013771-000.

1R06 Flood Protection Measures - Internal Flooding

a. Inspection Scope

The inspectors reviewed the UFSAR, flooding mitigation plans, and associated equipment inventories. The inspectors walked down Unit 1&2 Auxiliary Building Elevations 653 and 669 to verify that internal flood mitigating equipment, including the floor drains, sump pumps and level sensors, were consistent with licensee design requirements and risk analysis assumptions, and were in adequate configuration and condition to fulfill their design functions for a flood initiated by a failure of internal plant equipment. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the results of Procedure 2-PI-SFT-070-001.0, Performance Testing of Component Cooling Heat Exchangers 2A1, 2A2, Revision 8, to verify that the acceptance criteria and results appropriately considered differences between testing conditions and design conditions; that test results were appropriately categorized against pre-established acceptance criteria; that the frequency of testing was sufficient to detect degradation prior to loss of heat removal capability below design basis values; and that test results considered test instrument inaccuracies and differences.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities

.1 Unit 2 Steam Generator Inspection

a. Inspection Scope

The inspectors reviewed the implementation of the licensee’s program for monitoring the performance of the U2 steam generators. The inspectors reviewed the following program documents, procedures, and selected examination records:

- “Sequoyah Unit 2 Cycle 12 Eddy Current Examination Guidelines,” Revision 6
- “Sequoyah Nuclear Plant Unit 2 Cycle 12 Degradation Assessment,” Revision 1
- “TVA Analysis Training, Intelligent Array System, Fall Outage Season 2003,”
- Eddy current examination (ET) results (including graphics) for four SG tubes.
- In-situ pressure test results for SG tubes tested during this outage.

- SG tube repair (plugging) lists generated as a result of the Unit 2 SG ET examinations.

The inspectors also participated in three conference calls between NRC and the licensee concerning the conduct of the inspection. Of special interest, was a comparison between U-bend inspections conducted using the new “Intelligent Array System” and the established “Plus-Point” inspection system.

The above documents, records, and inspection techniques were compared to the Technical Specifications (TS), License Amendments and applicable industry established performance criteria to verify compliance.

b. Findings

No findings of significance were identified.

.2 Unit 2 Outage Activities

a. Inspection Scope

The inspectors observed in-process ISI work activities and reviewed selected ISI records. The observations and records were compared to the Technical Specifications (TS) and the applicable Code (ASME Boiler and Pressure Vessel Code, Section XI, 1989 Edition with no addenda) to verify compliance.

Portions of the following Unit 2 ISI were observed:

Ultrasonic (UT)	• Pipe Weld RC-35, 14" Diameter Pressurizer Surge Pipe
	• Pipe Thickness at Grid 203BP171, 16" Diameter Pipe Feed Water Line at West Valve Room
	• Pipe Thickness at Grid 2433R026, 6" X 4" Reducer for Feed Water Line at West Valve Room
Liquid Penetrant (PT)	• Pipe Weld at Support 2-SIH-103IA, Safety Injection System
	• Pipe Weld at Lugs at Support 2-SIH-80IA, Safety Injection System
Visual (VT)	• Pipe Support 2-SIH-103, Safety Injection System
	• Pipe Support 2-SIH-80, Safety Injection System
	• Pipe Support 2-CVCH-043, Chemical & Volume Control System
	• Pipe Support 2-CVCH-046, Chemical & Volume Control System
	• Pipe Support 2-CVCH-049, Chemical & Volume Control System

- Pipe Support 2-CVCH-075, Chemical & Volume Control System
- Pipe Support 2-CVCH-103, Chemical & Volume Control System
- Pipe Support 2-CVCH-105, Chemical & Volume Control System

Qualification and certification records for examiners and nondestructive examination (NDE) procedures for the above ISI examination activities were reviewed. Work Orders and examination documents were reviewed. The inspectors also performed a general walkdown in nearby areas to assess condition of the plant.

The inspectors reviewed Notification of Indication Form (NOI) No. 2-SQ-355 and Work Order No. 01-001446-000 for Indication and Repair Resolution found during the last refueling outage for adequacy of resolution.

The inspectors reviewed Work Order No. 00-011528-000 for an ASME Section XI, Class 3, ERCW 3" Diameter Stainless Steel Piping Modification and Replacement.

The inspectors reviewed the licensee's responses to NRC Bulletin 2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity. The inspectors selected samples from the leaks identified by the licensee during this Unit 2 outage and independently observed the components to assess the significance. The inspectors also independently performed a general walkdown inside the containment to search for leaks.

The inspectors reviewed the licensee's implementation of NRC Regulatory Issue Summary (RIS) 2003-01, Examination of Dissimilar Metal Welds, Supplement 10 to Appendix VIII of Section XI of the ASME Code. The licensee submitted a relief request to the NRC on October 15, 2003 to delay the examination to the fall of 2004. The inspectors discussed the issue with the licensee's engineers.

b. Findings

Introduction: A Green inspector-identified Non-Cited Violation (NCV) was identified for an inadequate inservice inspection which resulted in failure to identify a gap in a pipe support. The requirement stems from ASME Section XI Inservice Inspection activities required by Technical Specification 4.0.5 Inservice Inspection Program.

Description: On November 19, 2003, while observing a visual inservice examination for the pipe support 2-CVCH-105 for the ASME Section XI Class 1, 2" diameter Chemical & Volume Control System for the Seal Water Injection Line to Unit 2 Reactor Coolant Pump #4, the examiners failed to identify a gap between the pipe bottom and the supporting structural steel member. The examiners examined the support and did not identify any indications or discrepancies. The inspectors performed an independent examination after the licensee's examiners completed the examination and found a gap existed between the pipe bottom and the supporting structural steel member.

The inspectors pointed out the gap to the examiners and noted that the configuration drawing of the pipe support, No. 2-2-H34-0105-D1, Revision 0, shows there to be contact and no gap. The examiners replied that there are no requirements in the procedure to inspect the internal gaps or clearances for the supports. The gap was later measured as 3/16 inch. A gap would result in a non-functional support.

The gap indicates that the pipe is lifting up and not adequately supported by the structural steel member. Section 4.3.2.6, Fabricated Supports, of TVA General Engineering Specification G-43, Revision 13, requires in part that all vertical deadweight supports shall be in contact with the pipe upon initial installation. Piping or support changes could be service induced problems. This pipe support with the gap would differ from the pipe support design assumed in the original pipe stress analyses and the pipe support drawings, which could result in a different load distribution on nearby piping segments and supports. This could lead to pipe breaks or support failures.

Section B.5.1.6 of the TVA Nondestructive Examination Procedure N-VT-1, Visual Examination Procedure for ASME Section XI Preservice and Inservice, Revision 34 states that improper clearances of guides and stops is evidenced by upset metal surfaces, galling, deformation of members, and the moving of members beyond stop points. However, based on the above required inspection elements in the procedure the examiners still could not identify the gap existed in a pipe support. The inspectors did not determine the cause of the missed gap (i.e., inadequate procedure; insufficient training; etc.), but failure of the inspection program to detect unloaded supports could lead to more significant problems if left uncorrected.

The licensee issued Problem Evaluation Reports (PERs) 03-017128-000 and 03-017141-000 for the problems identified by the inspectors. The gap was found acceptable after the pipe stress analyses were re-performed with the gap condition and the new pipe support loads were re-examined.

Analysis: The inspectors determined that this finding was greater than minor because it was associated with the Initiating Events cornerstone and affected the objective of limiting the likelihood of events, such as pipe break and support failure events which upset plant stability. Failure to identify a non-functional support, which would change the pipe stress analyses and the pipe support design, could lead to more significant problems such as pipe breaks and support failures if left uncorrected. The issue was evaluated using the significance determination process. Since there was no increase in; 1) the likelihood of a primary or secondary LOCA; 2) the likelihood of a reactor trip and mitigating equipment or functions not being available; or 3) the likelihood of a fire or internal/external flood, this finding was determined to be of very low safety significance (Green).

Enforcement: Unit 2 Technical Specification 4.0.5, requires, in part that the Inservice Inspection Program provides control for inservice inspection of ASME Class 1, 2 and 3 components, including applicable supports and shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50.55a.

Enclosure

The TVA Inservice Inspection Program is documented as TVAN Standard Programs and Processes SPP-9.1, Revision 5, ASME Section XI. Sequoyah Nuclear Plant Surveillance Instruction 0-SI-DXI-000-114.2, Revision 18, ASME Section XI ISI/NDE Program Unit 1 and Unit 2 is established, in its purpose, to fulfill the inservice inspection requirements from 10 CFR 50.55a(g) and SPP-9.1 and to comply with the Inservice Inspection (ISI) nondestructive examination (NDE) requirements of the 1989 Edition of the ASME Boiler and Pressure Vessel Code, Section XI, Division 1, Articles 1000, 2000, 3000, and 6000.

IWF-2500, Examination Requirements, of ASME Section XI, Article IWF-2000 states that in part clearances of guides and stops, alignment of supports, and assembly of support items shall be examined in accordance with Table IWF-2500-1. Table IWF-2500-1 requires that Class 1 Piping Supports be examined using Examination Method - Visual, VT-3 and Acceptance Standard - IWF-3410. IWA-2213 VT-3 Examination for the general inspection requirements from Article IWA-2000 of the ASME Section XI states that VT-3 examinations are conducted to determine the general mechanical and structural condition of components and their supports by verifying parameters such as clearances, settings, and physical displacements; and to detect discontinuities and imperfections, such as loss of integrity at bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion. IWA-2213 also states that VT-3 includes examinations for conditions that could affect operability or functional adequacy of snubbers and constant load and spring-type supports. IWF-3410 Acceptance Standard lists “Improper clearances of guides and stops” to be one of the six conditions for component support conditions which are unacceptable for continued service.

Contrary to above, on November 19, 2003, the licensee failed to perform an adequate visual VT-3 Examination on pipe support 2-CVCH-105, in that the examiners did not identify a gap existing between the pipe bottom and the supporting structural steel member.

Because the failure to correctly identify the gap for this pipe support was of very low safety significance and the licensee documented this condition in PERs 03-017128-000 and 03-017141-000 for the corrective actions, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000328/2003006-02, Inadequate Inservice Inspection Resulted in Failure to Correctly Identify a Gap in Pipe Support 2-CVCH-105. The licensee subsequently re-performed the pipe stress analyses based on the gap condition and re-examined the pipe supports using the new loads from the pipe stress re-analyses and determined that the gap found was acceptable.

1R11 Licensed Operator Requalification

.1 Biennial Requalification Inspection

a. Inspection Scope

During the week of October 6-10, 2003, the inspectors reviewed documentation, interviewed licensee personnel, and observed the administration of simulator operating tests and Job Performance Measures (JPMs) associated with the licensee's operator requalification program. Each of the activities performed by the inspectors was done to assess the effectiveness of the licensee in implementing requalification requirements identified in 10 CFR 55, "Operators' Licenses." Evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG-1021, "Operator Licensing Examination Standards for Power Reactors," and Inspection Procedure 71111.11, "Licensed Operator Requalification Program." The inspectors also reviewed and evaluated the licensee's simulation facility for adequacy for use in operator licensing examinations. The inspectors observed two crews during the performance of the operating tests. Documentation reviewed included written examinations, JPMs, simulator scenarios, licensee procedures, on-shift records, licensed operator qualification records, watchstanding and medical records, simulator modification request records and performance test records, the feedback process, and remediation plans. The records were inspected against the criteria listed in Procedure 71111.11. Documents reviewed during the inspection are listed in the Attachment.

Following the completion of the annual operating examination testing cycle which ended on December 12, 2003, the inspectors reviewed the overall pass/fail results of the individual JPM operating tests, and the simulator operating tests administered by the licensee during the operator licensing requalification cycle. These results were compared to the thresholds established in Manual Chapter 609 Appendix I, Operator Requalification Human Performance Significance Determination Process.

b. Findings

Introduction: A Green NCV was identified for failure to certify qualifications and status of licensed operators were current and valid and that the requirements of 10 CFR 55.53, "Conditions of Licenses" for license reactivation were met prior to their resumption of license duties.

Description: The inspectors identified the licensee was unable to retrieve official records which documented the reactivation process had been completed and met the requirements of 10 CFR 55.53 , "Conditions of License," for 9 of 13 licensed operators who had reactivated between October 1, 2001 through September 30, 2003. The inspectors noted that only the four most recent reactivation records were held by the licensee. All previous historical records of licensed operator reactivation were not accounted for at the time of the inspection.

The licensee took prompt corrective action and performed an exhaustive search of their logs and records in an attempt to reconstruct some of the lost data. The licensee found no evidence that any inactive licensed operator ever stood a licensed position watch on a unit during this period.

In addition, the licensee evaluated the extent of condition and found additional problems that were associated with the reactivation process. The inspectors noted that the licensee found errors in the Active/Inactive operator database used by Operations to report whether an individual is qualified to stand watch. Two operators were listed as inactive when they had stood the required watches to maintain their active status, and one license reactivation was not recorded in the database. The two operators who were listed as inactive in the database actually stood watch in the control room even though listed as inactive that quarter. The Active/Inactive database was apparently not being used by shift management to ensure inactive operators did not stand shift.

Analysis: The inspector determined that the licensee's failure to maintain and furnish the reactivation records of licensed operators is a performance deficiency because the licensee is required to certify qualifications and status of the licensed operator are current and valid and that the requirements of 10 CFR 55.53, “Conditions of Licenses” for license reactivation have been met prior to their resumption of license duties.

Licensee Procedure OPDP 1-4, “Conduct of Operations,” specified Lifetime Retention for the reactivation record form OPDP 1-4, “Licensee Documentation Form (SRO & RO) and ODM 1.0 Appendix T, “Certification of Reactivation of an Inactive NRC License.” Appendix T contained specific data which was required to be documented for each reactivation and should be attached to form OPDP 1-4.

The inspectors were unable to verify the reactivation process had been properly completed in accordance with all regulatory requirements specified in 10 CFR 55.53 for nine of the thirteen operators whose records were selected for review.

Operator qualification records document and allow independent verification and confirm appropriate measures were taken to ensure licensed operators were adequately trained and met the legal requirements to manipulate the controls or direct the operation of a nuclear power plant. The requirements associated with reactivation of inactive operators minimizes the risks associated with human performance error in the operation of the plant. The finding is greater than minor because it is associated with the Mitigating Systems Cornerstone human performance attribute that affects the availability, reliability, and capability of operators to respond to initiating events to prevent undesirable consequences that could pose a potential risk to operations. The finding was evaluated using the Operator Requalification Human Performance SDP and was determined to be a finding of very low safety significance because there was no evidence of an inactive operator standing a watch. Since more than 20% of the reactivation records had deficiencies in that they were not available and could not be verified to meet reactivation requirements, the issue was determined to be a Green finding.

Enforcement: 10 CFR 55.53.f "Conditions of Licenses" requires, in part, that an authorized representative of the facility licensee shall certify that qualifications and status of operator licensees are current and valid and that the specific requirements for license reactivation have been met prior to the resumption of license duties by licensed operators. Contrary to the above, the licensee did not maintain and could not furnish nine of thirteen reactivation qualification records selected for review, nor could any previous historical records be located. This violation is associated with an inspection finding that is characterized by the Significance Determination Process as having very low risk significance (Green) and is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000327, 328/2003006-03, Failure to Maintain Qualification Records for Licensed Operator Reactivation The violation is in the licensee's corrective action program as PER 03-013738-000.

.2 Quarterly Inspection by Resident Staff

a. Inspection Scope

The inspectors observed just-in-time simulator training on December 7, 2003. The training involved briefing the operators on what to expect during pull-to-critical and low power physics testing on Unit 2 and practice at the control room manipulations involved in those activities. The inspectors observed crew performance in terms of communications; ability to take timely and proper actions; prioritizing, interpreting and verifying alarms; correct use and implementation of procedures, including the alarm response procedures; timely control board operation and manipulation, including high-risk operator actions; oversight and direction provided by shift manager, including the ability to identify and implement appropriate TS actions; and group dynamics involved in crew performance. The inspectors also reviewed simulator fidelity to verify that differences between Unit 2 and the simulator were appropriately addressed.

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation

a. Inspection Scope

The inspectors reviewed the following six maintenance activities to verify the effectiveness of the activities in terms of: 1) appropriate work practices; 2) identifying and addressing common cause failures; 3) scoping in accordance with 10 CFR 50.65(b); 4) characterizing reliability issues for performance; 5) trending key parameters for condition monitoring; 6) charging unavailability for performance; 7) classification in accordance with 10 CFR 50.65(a)(1) or (a)(2); 8) appropriateness of performance criteria for Structures, Systems, and Components (SSCs) and functions classified as (a)(2); and 9) appropriateness of goals and corrective actions for SSCs and functions classified as (a)(1). Documents reviewed are listed in the attachment.

- Addition of incorrect lubricant to ERCW Strainer A2A-A without a work document
- Incorrect lubricant discovered in EDG 1A-A Engine 2
- Wrong lubricant found in TDAFW Pump 2A-S
- Through-wall leakage in flood-mode decay heat removal header
- 1A Containment Spray System unavailability
- ERCW freeze protection maintenance issues

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the following four activities to verify that the appropriate risk assessments were performed prior to removing equipment from service for work. The inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4), and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly re-assessed and managed. The inspectors verified the appropriate use of the licensee's risk assessment tool and risk categories in accordance with Procedure SPP-7.1, Work Control Process, Revision 4, and Instruction, 0-TI-DSM-000-007.1, Equipment to Plant Risk Matrix, Revision 7.

- Closure of Pressurizer Power-Operated Relief Valve (PORV) Block Valves to Assess Valve Leakage

- Blocking of a Malfunctioning No. 7 Heater Drain Valve pending Repair Activities

- Removal of Unit 1 B-Train ERCW ESF and CCS Headers for Planned Maintenance

- Unit 2 Integrated Risk Management during Transition through Mode 4

b. Findings

Two findings were identified by inspectors as discussed below:

.1 Closure of PORV Block Valves

Introduction: The inspectors identified a green NCV for failure to comply with plant configuration control procedures.

Description: On February 27, 2003, operators closed one Unit 1 and two Unit 2 PORV block valves at the recommendation of two Engineering Work Requests (EWRs) generated to troubleshoot indications of PORV seepage. The other Unit 1 PORV block valve had been closed previously on February 19, 2003, for the same reason. This configuration was maintained until March 10, 2003, when the Unit 2 block valves were re-opened. The Unit 1 block valves were re-opened the following week.

The inspectors questioned the propriety of using EWRs to close the valves and whether the closures had been evaluated in the site risk plan. The licensee initiated PER 03-002050-000 and confirmed that EWRs were inappropriate for changing the plant configuration. The licensee further confirmed that the activity did not use an emergent worksheet. Therefore, the work week manager was unaware of the need to perform a risk assessment. The Licensee confirmed that if the proper process been utilized (troubleshooting WO), the work control process would have prevented this error.

The inspectors determined that the use of EWRs to close the valves did not comply with procedure SPP-10.1, System Status Control, Revision 1, guidance instructing the shift manager, his designee, and other responsible individuals to ensure that all activities that change the configuration of plant equipment are authorized by an approved plant procedure, clearance, work order, or Temporary Alteration Control Form (TACF).

Analysis: This finding was more than minor because it affected the configuration control attribute of the Initiating Event cornerstone. Alteration of safety related equipment configuration outside of approved processes would, if left uncorrected, result in a more significant safety concern. Concurrent closure of PORV block valves disabled PORV automatic over-pressure transient protection. While not prohibited by technical specifications, this action removed an over-pressure reactor trip barrier and could challenge the pressurizer safety valves in response to an over-pressure transient. Because closure of the block valves only affected the initiating event cornerstone and did not directly contribute to the likelihood of a primary system LOCA initiator, this finding was considered to be of very low safety significance (Green).

Enforcement: TS 6.8.1.a requires that procedures be implemented covering the activities in Regulatory Guide (RG) 1.33, Revision 2, Appendix A. Paragraph 1c of Appendix A recommends procedures for equipment control. Licensee procedure SPP-10.1 requires that all activities that change the configuration of plant equipment be authorized by an approved plant procedure or work document. Contrary to the above, on February 27, 2003, the licensee failed to implement Procedure SPP-10.1 in that all pressurizer PORV block valves were closed without an approved plant procedure or work document for a period exceeding ten days without appropriate configuration control or prior risk assessment. Because this violation was determined to be of very low safety significance (Green), it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 05000327,328/2003006-04, Failure to Comply with Configuration Control Procedures. This violation is in the licensee's corrective action program as PER 03-002050-000.

.2 Unit 1B Train ERCW ESF and CCS Headers

Introduction: The inspectors identified a green NCV for the failure to manage risk when removing the Unit 1 B-Train components from service for a CCS and ERCW ESF header outage.

Description: At 0100 on November 20, 2003, the licensee placed clearance tags on the 1B-B CCP in connection with scheduled maintenance on the Unit 1 B-Train CCS and ERCW ESF headers. Later, the inspectors questioned operators and the work week manager concerning the plant configuration and published risk condition for that maintenance. At approximately 0930, having confirmed that it had been tagged in error, and was not part of the scheduled maintenance plan, the licensee restored the 1B-B CCP to available status. The licensee also acknowledged that the Unit 1 risk condition, published in the plan of the day and understood by operators as green, was also in error. The previously assessed risk condition for the scheduled maintenance was Yellow, but the actual risk condition, with the unavailable 1B-B CCP, could not be assessed in the licensee risk assessment program. The inspectors noted that the actual configuration would not have been allowed by plant risk procedures which would have required the risk to be reassessed or the 1B-B CCP not tagged. The licensee had recognized that the tagging of the 1B-B CCP was not part of the scheduled maintenance plan, but their actions did not fully preclude it from being tagged out of service.

Analysis: This finding is greater than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone and it affected the availability of the 1B-B CCP. It resulted in an unplanned 8.5-hour unavailability of the 1B-B CCP and an unplanned, unrecognized increase in risk. The finding was of very low safety significance (Green) because it did not represent an actual loss of safety function of a system nor did it represent an actual loss of safety function of a single train for greater than its technical specification-allowed outage time.

Enforcement: 10 CFR 50.64(a)(4) states, in part, that before performing maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to this, on November 20, 2003, the licensee placed Unit 1 in a configuration different from than that in the risk assessment and resulted in a situation not allowed by site risk procedures. Because this violation was determined to be of very low safety significance (Green), it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 05000327/2003006-05, Failure to Manage the Risk from Proposed Maintenance Activities. This violation is addressed in the licensee’s corrective action program in PERs 03-017088-000, 03-017124-000, and 04-770254-000.

1R15 Operability Evaluations

a. Inspection Scope

For the three operability evaluations described in the PERs listed below, the inspectors evaluated the technical adequacy of the evaluations to ensure that operability was properly justified and that the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors reviewed the UFSAR to verify that the system or component remained available to perform its intended function. In addition, the inspectors reviewed implemented compensatory measures to verify that the compensatory measures worked as stated and the measures were adequately controlled. The inspectors also reviewed a sampling of PERs to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the attachment.

- PER 03-013679-000, Gas Found in Unit 2 Emergency Boration Piping

- PER 03-015083-000, Hydrogen Recombiner 2B Thermocouple Selector Switch Broke During Surveillance

- PER 03-16471-000, Delay Getting to RHR When Using ARVs

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed the cumulative effects all open operator work-arounds, auxiliary unit operator round deficiencies, selected caution orders, and standing orders to determine whether or not they could affect the reliability, availability, and potential for misoperation of a mitigating system; affect multiple mitigating systems; or affect the ability of operators to respond in a correct and timely manner to plant transients and accidents. The inspectors also assessed whether operator work-arounds were being identified and entered into the corrective action program at an appropriate threshold. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed Design Change Notice (DCN) D21426, Replace Existing Nukon Fiberglass Insulation Installed on the Pressurizer Safety Valve Loop Seal Piping with Mirror Reflective Metal Insulation, Revision A, and interviewed engineering personnel regarding the modification and associated post-modification testing to verify that (1) the design bases, licensing bases, and performance capability had not been degraded through this modification, and (2) the modification was not performed during increased risk-significant configurations that placed the plant in an unsafe condition. The inspectors also reviewed applicable sections of the UFSAR, plant modification procedures, system drawings, supporting analyses, technical specifications, and related PERs.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the two post-maintenance tests listed below to verify that procedures and test activities ensured system operability and functional capability. The inspectors reviewed the licensee's test procedure to verify that the procedure adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure were consistent with information in the applicable licensing-basis and/or design-basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test or reviewed the test data, to verify that test results adequately demonstrated restoration of the affected safety functions. Additional documents reviewed are listed in the attachment.

- WO 03-005324-008, Test Underground Portion of Power Cable for ERCW Pump R-A to Clear 91-18 Issue
- WO 01-002313-000, Replace Motor-Driven Auxiliary Feedwater Pump 2A

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors reviewed the outage safety plan and contingency plans for the Unit 2 refueling outage to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. Between November 10, 2003, and December 11, 2003, the inspectors observed portions of the shutdown, cooldown, refueling, heatup, and startup activities to verify that the licensee maintained defense-in-depth commensurate with the outage risk plan and applicable TS. The inspectors monitored licensee controls over the outage activities listed below. Documents reviewed during the inspection are listed in the attachment.

- Licensee configuration management, including daily outage reports, to evaluate defense-in-depth commensurate with the outage safety plan and compliance with the applicable TS when taking equipment out of service.

- Licensee implementation of clearance activities to ensure that equipment was appropriately configured to safely support the work or testing.

- Installation and configuration of reactor coolant instruments to provide accurate indication and an accounting for instrument error.

- Controls over the status and configuration of electrical systems and switchyard to ensure that TS and outage safety plan requirements were met.

- Decay heat removal processes to verify proper operation and that steam generators, when relied upon, were a viable means of backup cooling.

- Controls to ensure that outage work was not impacting the ability to operate the spent fuel pool cooling system during and after core offload.

- Reactor water inventory controls, including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.

- Reactivity controls to verify compliance with TS and that activities which could affect reactivity were reviewed for proper control within the outage risk plan.

- Containment closure for control of containment penetrations in accordance with refueling TS, to ensure that containment closure could be achieved during selected configurations, and to verify maintenance of secondary containment in accordance with TS.

- Defueling and refueling activities for compliance with TS, to verify proper tracking of fuel assemblies from the spent fuel pool to the core and to verify that foreign material exclusion was maintained.

- Reduced inventory and mid-loop conditions for commitments to Generic Letter 88-17 to verify that these commitments were in place, that plant configuration was in accordance with those commitments, and that distractions from unexpected conditions or emergent work did not affect operator ability to maintain the required reactor vessel level.

- Heatup and startup activities to verify that appropriate prerequisites for mode changes were met prior to changing modes, that containment integrity was established, that debris was not left that could affect the containment sump, and that core operating limit parameters were consistent with core design.

b. Findings

Introduction: The inspectors identified a green NCV for a self-revealing failure to comply with plant procedures when draining to mid-loop conditions on Unit 2.

Description: On November 29, 2003, operators began draining the Unit 2 RCS in order to remove steam generator nozzle dams. When the RCS was drained to an indicated level on the primary level indicating system (Mansell) of 696 feet 0 inches, two and a half inches below the top of the hot leg, the secondary level system (Ultrasonics) continued to indicate that the hot leg pipe was full. The licensee investigation of this self-revealing problem determined that Valve 2-68-597, a 3/4 inch head vent valve, was closed. Because this resulted in a slight vacuum in the reactor head as water level decreased, it caused the Mansell system, which compares pressure at the bottom of the cold leg to pressure at the top of the pressurizer, to indicate a lower level than was actually present. The licensee also determined that Valve 2-68-597 was required to be tagged opened by procedure before beginning to drain and that operators failed to comply with the Procedure 0-GO-13, Reactor Coolant System Drain and Fill Operations, Revision 42, by continuing past the step with the valve closed. The inspectors therefore considered the cause of the finding was related to the cross-cutting element of human performance.

Analysis: This finding was more than minor because configuration control errors while in reduced inventory or mid-loop conditions, where safety margins are small, can result in a loss of decay heat removal capability. Because decay heat removal capability was not lost and the unit did not enter mid-loop conditions with the valve closed, this finding was considered to be of very low significance (Green).

Enforcement: TS 6.8.1.a requires that procedures be implemented covering the activities in RG-1.33, Revision 2, Appendix A. Paragraph 3.a of Appendix A recommends procedures for filling, venting, and draining the RCS. Licensee procedure 0-GO-13 provided instructions for draining the RCS to reduced inventory and mid-loop conditions. Contrary to the instructions in Procedure 0-GO-13, on November 29, 2003, the licensee continued past the step that required Valve 2-68-597 to be opened.

Because this violation was determined to be of very low safety significance (Green), it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 05000328/2003006-06, Failure to Comply with Procedure for Draining to Mid-loop. This violation is in the licensee's corrective action program as PER 03-017840-000.

1R22 Surveillance Testing

a. Inspection Scope

For the three surveillance tests identified below, by witnessing testing and/or reviewing the test data, the inspectors verified that the systems, structures, and components involved in these tests satisfied the requirements described in the TS surveillance requirements, the UFSAR, applicable licensee procedures, and that the tests demonstrated that the SSCs were capable of performing their intended safety functions. Documents reviewed are listed in the attachment. Those tests included the following:

- 2-SI-SXP-003-201.A, Motor-Driven Auxiliary Feedwater Pump 2A-A Performance Test, Revision 9*
- 0-SI-MIN-061-004.0, Ice Condenser Top Deck Doors, Revision 3**
- 0-SI-MIN-061-107.0, Ice Condenser Floor Drains, Revision 0**

*This procedure included inservice testing requirements.
**This procedure included an ice condenser system surveillance.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the two temporary modifications listed below, to verify that the design was adequate, the modification was properly installed, the modification did not affect system operability, drawings and procedures were appropriately updated, and post-modification testing was satisfactorily performed. Documents reviewed are listed in the attachment. Those modifications included the following:

- TACF 2-03-034-046, 2B MFP Governor Valve Positioner Modification
- TACF 2-03-038-061, Ice Condenser Air Handling Unit

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors evaluated the conduct of a licensee emergency drill on October 17, 2003, to identify any weaknesses and deficiencies in classification, notification, and Protective Action Recommendation (PAR) development activities. The inspectors also attended the licensee critique of this drill to compare any inspector observed weakness with those identified by the licensee in order to verify whether the licensee was properly identifying failures.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors sampled licensee submittals for the PIs listed below for the period from January 1, 2002, through September 30, 2003, for the Safety System Unavailability indicators, and July 1, 2002, through September 30, 2003, for the Safety System Functional Failures indicators, respectively.

To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in NEI 99-02, “Regulatory Assessment Indicator Guideline,” Revision 2, were used to verify the basis in reporting for each data element.

Cornerstone: Mitigating Systems

- Safety System Unavailability: Unit 1 Emergency AC Power
- Safety System Unavailability: Unit 2 Emergency AC Power
- Safety System Unavailability: Unit 1 High Pressure Injection System
- Safety System Unavailability: Unit 2 High Pressure Injection System
- Safety System Functional Failures for Unit 1
- Safety System Functional Failures for Unit 2

The inspectors reviewed portions of the operations logs and raw PI data developed from monthly operating reports and discussed the methods for compiling and reporting the PIs with cognizant engineering personnel. The inspectors also independently calculated selected reported values to verify their accuracy.

LERs issued during the referenced timeframe for Safety System Functional Failures were also reviewed and are listed in the Attachment.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. This review was accomplished by reviewing the description of each new PER and attending daily management review committee meetings.

.1 Annual Sample Review of Freeze Protection Problems of January 2003

a. Inspection Scope

On January 2003, when outside air temperature decreased to 6°F, several equipment failures occurred on each unit. In addition to the Unit 2 RWST wide range level transmitters discussed in Section 4OA3 of this report, the following components froze on the same day: a Unit 2 feedwater flow transmitter, a Unit 1 RWST narrow-range level transmitter, a Unit 1 AFW flow transmitter, a Unit 1 main transformer low voltage bushing cooling flow switch, a fire storage tank drain valve, and some chlorination valves for the ERCW system. The inspectors performed a detailed review of these occurrences to evaluate the licensee's overall corrective action response to the problems. The inspectors reviewed the PER and root cause analysis for the freezing problems on the RWST, a common cause analysis for all of the instances, and a PER and root cause analysis on the operations freeze protection program. Documents reviewed are listed in the attachment.

b. Findings and Observations

There were no findings identified; however, the inspectors determined that procedures were a common cause of the events and identified that there was a missed opportunity to identify the freezing RWST instruments prior to entering TS 3.0.3 on January 25, 2003.

In PER 03-002446-000, the licensee performed a barrier analysis on the freeze events of January 2003 and concluded that there was no predominant common cause for these events. However, four of the eight incidents reviewed in this PER occurred despite a procedure that existed to prevent it. From this the inspectors concluded that the freeze protection procedures for both operations and maintenance were a common cause. Even though not specifically identified as a common cause in the PER, corrective actions were taken by the licensee to correct the procedure problems.

In PER 03-000783-000, the licensee analyzed the Operation's freeze protection program for weaknesses. The root cause analysis of this PER originally found that the program was lacking in the area of increased monitoring and sensitivity to critical instruments that were at risk. The same root cause analysis indicated that freeze protection surveillance procedures were acceptable and that a surveillance by itself could not prevent an item from freezing if it were beyond its design operating criteria. Because of the early warning nature of a test, which would allow any failed equipment to be repaired before cold weather caused any components to become inoperable, the inspectors determined that a surveillance or test of freeze protection equipment could prevent an item from freezing. The RCA of this PER was revised on December 1, 2003, and no longer indicates that the procedures were adequate.

In reviewing the events of January 24, 2003, the inspectors noted that one of the Unit 2 RWST WR level instruments actually froze several hours before it was discovered. This was not addressed in any of the PERs dealing with the freezing events. Had the first inoperable instrument been identified earlier, more time was available to correct the problem and the need for entry into TS 3.0.3 might have been eliminated. This constituted a missed opportunity to identify the problem. The revision to the PER referenced earlier addressed this issue and a corrective action was added to put a computer monitor on the level instruments.

.2 Annual Sample Review of Problems with Incorrect Lube Oil in Safety-Related Equipment

a. Inspection Scope

The inspectors reviewed licensee corrective actions in connection with a series of licensee-identified adverse conditions in which the incorrect lubricant was discovered in safety-related equipment. Specifically, the inspectors reviewed the addition of incorrect lubricant to: (1) emergency diesel generator (EDG) 1A-A engine 2, (2) turbine-driven auxiliary feedwater (TDAFW) pump 2A-S, and (3) essential raw cooling water (ERCW) strainer 2A-A. The inspectors interviewed personnel, physically inspected bulk lubricant storage areas, and reviewed applicable documentation, including a significant adverse condition involving the addition of incorrect lubricant in multiple risk-important components during the period from approximately 1998 to 2000. Documents reviewed are listed in the attachment.

b. Findings and Observations

There were no findings identified; however, the inspectors noted that previous problems with administrative controls for the handling of bulk lubricants had been documented in NCV 50-327,328/00-02-01. Corrective actions for that NCV were directed at problems in the turbine building and only partially implemented in other areas. Therefore, the narrow scope of these actions were not effective at fixing similar problems in the EDG building.

This contributed to the installation of 55 gallons of the wrong lubricant in EDG 1A-A engine 2. In addition, because of the partial implementation of corrective actions, the licensee was not effective at verifying the correct oil in other safety-related equipment. This constituted a licensee-identified violation which is discussed in section 4OA7.

.3 Annual Sample Review of Problems with Pratt Valves

a. Inspection Scope

The inspectors reviewed licensee actions to resolve problems associated with Pratt Butterfly Valves because of the large number of problems and because a failure of a Pratt valve resulted in an unplanned reactor trip in 2002. The inspectors reviewed selected applicable work and corrective action documents, root cause and operability determinations, design modifications, and procedure changes implemented to address these issues during the period from May 2001 through December 2003. Documents reviewed are listed in the attachment.

b. Findings and Observations

There were no findings identified. The inspectors reviewed documentation illustrating that the licensee had identified problems with hard-to-stroke Pratt Valves and hardening/swelling of the rubber valve seats at least as early as 1997. Cracked valve disks were identified as early as 2000. A licensee review identified eight such issues associated with site Pratt valves between 1997 and 2000.

In May 2000, the motor operator for 2-FCV-70-156, the 18-inch Train A RHR Heat Exchanger component cooling flow control valve, was found to draw high current, which suggested potential valve internal binding. However, a PER was not initiated, but, a work order was written to replace the valve during an upcoming outage. In May 2001, before its replacement, the valve failed to re-position during a routine surveillance. The motor operator thermal overloads opened. Operators declared the 2A RHR train inoperable and initiated a PER. Following this and other Pratt Valve failures, the licensee initiated PER 01-005036-000, upgraded the PER to level B, performed an extensive evaluation of extent of condition review, and has implemented an aggressive sampling and corrective action schedule to preclude further problems.

Occurrences similar to the failure of Valve 2-FCV-70-156 have been identified by the licensee in the common cause evaluation for multiple reactor trips discussed in PER 02-015571-000. The inspectors noted that this was another occurrence of a previously-identified problem.

4OA3 Event Followup

.1 (Open) LER 05000327/2003-001-00, Manual Reactor Trip as a Result of a Main Generator Trip and Loss of Load

a. Inspection Scope

On August 28, 2003, the Unit 1 main generator output breakers tripped while operators were performing quarterly oil trip tests at the turbine front standard. Approximately 25 seconds after the generator output breakers opened, operators manually tripped the Unit 1 reactor. This manual reactor trip resulted in a turbine trip. At the time of this event, it appeared as though the reactor protection system had failed to automatically trip the reactor in response to a turbine trip. Because of this, the NRC conducted a special inspection of this event. The results of that inspection are documented in IR 05000327, 328/2003010.

The inspectors reviewed the LER to evaluate the cause of the event and any licensee performance deficiencies associated with the cause. This LER will remain open pending NRC evaluation of the circumstances surrounding licensee actions to close the MSIVs, including steam flow indication and the response of the unit as compared with the simulator.

b. Findings

Introduction: The inspectors identified a green finding for a self-revealing failure to maintain configuration control of the oil valves in the turbine front standard resulting in a reactor trip of Unit 1.

Description: The licensee identified the cause of the event to be an improperly closed isolation valve for Pressure Switch 1-PS-47-76, which setup the turbine control logic to trip open the main generator output breakers when the turbine thrust bearing oil trip test was performed. The licensee further identified two possible causes for the valve closure, both of which related to the control of plant configuration. One was the failure to properly implement the verification process. Switch 1-PS-47-76 was calibrated during the Unit 1 outage in the Spring of 2003. At that time, the turbine trip block, where the switch was located, was disassembled for maintenance. Subsequently, only a single verification of isolation valve position was performed, although the calibration procedure called for two verifications to be done independently.

The second possible cause of the isolation valve closure was failure to maintain a configuration control process. During the startup from the outage in the Spring of 2003, the licensee encountered trouble latching the turbine. In troubleshooting the problem, which included manipulating at least one valve at the turbine front standard, the licensee failed to use a work order or approved procedure.

The inspectors reviewed the LER, the post-trip report attached to PER 03-011940-000, and the addendum to the root cause analysis for PER 03-011940-000. The inspectors determined that the mispositioned isolation valve for Pressure Switch 1-PS-47-76 did not meet plant configuration control guidance that requires all activities that change the configuration of plant equipment be authorized by an approved plant procedure, clearance, work order, or TACF. Either of the two possible causes constituted a human performance error.

Analysis: This finding was more than minor because it affected the configuration control attribute of the initiating event cornerstone and challenged the ability of operators and the reactor protection system to safely shut down the plant. With the isolation valve to Pressure Switch 1-PS-47-76 inappropriately closed, a generator load rejection and subsequent reactor trip were assured when the turbine thrust bearing trip test was performed. Because no mitigating system was affected, this finding was considered to be of very low safety significance (Green).

Enforcement: Because the affected equipment was non-safety related, no violation of regulatory requirements occurred. Therefore, this finding is identified as FIN 05000327/2003006-07, Failure to Maintain Configuration Control of Turbine Oil Valves Resulted in Reactor Trip.

.2 (Closed) LER 05000328/2002-001-00, Inadvertent Auxiliary Feedwater System Actuation Signal

This LER documented a condition where an inadvertent AFW actuation signal was generated during the course of the Unit 2 shutdown in preparation for a refueling outage. The unit had been tripped in accordance with procedure and was stable in Mode 3, and the RCS temperature had decreased to approximately 545° F. The AFW system was in manual control with AFW level control valves throttled to limit plant cooldown and the steam dump system was controlling RCS temperature in the pressure control mode. The feedwater isolation signal, which had been generated by the plant trip, and the main feedwater pump trips were re-set, in accordance with procedure. Due to residual heat of the reactor, the RCS temperature gradually increased to 551°F and then decreased below the 550°F setpoint for generating the feedwater isolation and AFW actuation signals as the steam dumps continued to control RCS temperature. Operators recovered from AFW actuation and moved the unit to Mode 4.

The licensee determined that the cause of the event to be an incorrect understanding of the plant response by the operators as a result of preconditioning from inaccurate simulator modeling. The modeled end-of-life decay heat was less than the actual decay heat. No new findings were identified by the inspectors' review. This finding constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC Enforcement Policy. The licensee documented the problem in PER 02-004059-000. This LER is closed.

.3 (Closed) URI 50-328/2003-003-02, Frozen RWST Instrumentation (NOED 03-6-001) (Closed) LER 05000328/2003-002-00, Limiting Condition for Operation 3.0.3 Was Entered when Two Refueling Water Storage Tank Level Transmitters Failed during Cold Weather Conditions

Introduction: The inspectors identified a green NCV for an inadequate procedure for freeze protection of the Unit 2 RWST level transmitters.

Description: On January 24, 2003, Unit 2 RWST wide range level transmitters 2-LT-63-50 and 2-LT-63-52 failed when the impulse lines froze due to a failure of the strip heaters within the transmitter enclosures. The licensee requested, and the NRC granted, a one-time 48-hour reduction in the required minimum number of operable channels to permit the licensee to repair the transmitters without shutting down the unit. The inspectors opened this URI pending evaluation of the root cause of the problem leading to the request for enforcement discretion and any associated enforcement. The licensee ultimately repaired the RWST transmitters within the allowable TS LCO time and did not utilize the 48-hour reduction.

The licensee determined the root cause of the failure of the strip heaters to be two damaged power supply cables. These two cables had experienced excessive tension from pulling kinked cables during installation in 1982. This resulted in broken conductors and an open circuit to each strip heater that prevented them from operating in extremely cold weather.

The inspectors reviewed the root cause analysis of PER 03-000715-000 and reviewed the freeze protection procedures in effect at the time of the event. Procedure 2-PI-EFT-234-706.0, Freeze Protection Heat Trace Functional Test, Revision 15, which was performed on January 20, 2003, tested the strip heaters for the RWST wide range level instruments and listed the acceptance criteria as warmth felt by hand. While the actual failure of the strip heaters can be attributed to the incorrect installation of the power cables, the inspectors determined that this method of checking for heater operation was not capable of verifying sufficient current and thus could not detect any degradation or failure due to the combination of a kinked cable and extreme cold. Therefore, the inspectors concluded that Procedure 2-PI-EFT-234-706.0 was inadequate to protect the RWST level transmitters from freezing.

Analysis: This finding was more than minor because, if left uncorrected, all four RWST wide range level instruments would have been affected. Because the safety function provided by the four instruments was not actually lost, this finding was considered to be of very low significance (Green).

Enforcement: 10 CFR 50, Appendix B, Criterion V, requires that activities affecting quality be prescribed and accomplished using instructions, procedures, or drawings appropriate to the circumstances and include appropriate acceptance criteria. Contrary to this, on January 20, 2003, the licensee used an inadequate procedure to verify operation of the wide range level instrument freeze protection features on the safety-related RWST. Procedure 2-PI-EFT-234-706.0, a quality-related procedure, contained inappropriate acceptance criteria for monitoring the RWST freeze protection features in extreme cold. Because this violation was determined to be of very low safety significance (Green), it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 05000328/2003006-08, Inadequate Procedure for Protecting RWST Level Instruments. This violation is in the licensee's corrective action program as PER 03-000715-000. This URI and LER are closed.

.4 (Closed) URI 50-328/2003-003-03, Containment Purge Valve Leakage (NOED 03-2-004)
(Closed) LER 05000328/2003-003-00, Excessive Leakage of a Containment Purge System Containment Isolation Valve

On February 27, 2003, Unit 2 containment penetration X-6 purge valves 2-FCV-30-50 and 2-FCV-30-51 failed a local leak rate test due to a broken key on the stem of the inboard valve. The licensee requested and was granted an additional 144 hours beyond the TS Allowed Outage Time to identify the source of the leakage, repair or replace the valve(s), and to perform verification testing without shutting down the unit. The inspectors opened this URI pending evaluation of the root cause of the problem leading to the request for enforcement discretion and any associated enforcement.

The licensee determined the cause to be inadequate engagement of the key between the actuator yoke and valve stem, resulting in a failure of the key. The inspectors reviewed the LER and the root cause analysis for PER 03-002020-000 and no findings of significance were identified. However, the inspectors noted that a formal root cause was not performed because the valve and actuator were not disassembled in the controlled fashion needed for root cause analysis methods. This URI and LER are closed. The cause of this event did not constitute a violation of NRC requirements.

4OA4 Cross-cutting Issues

Section 1R20 describes a human performance error where licensee operators incorrectly continued past a procedural step to open the reactor head vent prior to draining to mid-loop conditions. Consequently, a slight vacuum developed in the reactor head as water level decreased, causing level indicators to indicate a lower level than was actually present.

Section 4OA3.1 describes a human performance error where the licensee improperly closed a main turbine pressure switch isolation valve. As a result, the turbine control logic was assured to trip open the main generator output breakers when the turbine thrust bearing oil trip test was performed. The cause of the error was determined to be either failure to properly implement the verification process or failure to control configuration during troubleshooting.

4OA5 Other Activities

.1 NRC Temporary Instruction (TI) 2515/152, Revision 1, Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02)

a. Inspection Scope

The inspectors reviewed the Unit 2 bare metal visual examination performed by the licensee in response to the NRC Bulletin 2003-02, Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity, dated August 21, 2003. The inspection guidelines were provided in TI 2515/152, Revision 1. Additional documents are listed in the attachment.

b. Findings and Observations

No findings of significance were identified. Per the reporting requirements of TI 2515/152, Revision 1, the following attributes were observed:

Verification that visual examination was performed by qualified and knowledgeable personnel

Two teams of three individuals performed the examination of the Unit 2 lower head. One team worked the day shift and one team worked the night shift. One individual on each shift was a licensee Level III Non-Destructive Examination (NDE) qualified to perform VT-2 inspections. The inspectors reviewed the qualification records and verified that these individuals were certified as Level III VT-2 inspectors. The other members of each team were vendor employees that operated the remote video camera equipment. These individuals had performed the same examinations on the Unit 1 upper and lower heads in the spring of 2003 and the Unit 2 upper head in the spring of 2002. The inspectors interviewed all of the individuals and noted they were knowledgeable of the criteria to determine leakage.

Verification that visual examination was performed in accordance with demonstrated procedures

The inspectors reviewed Procedure N-VT-17, Visual Examination for Leakage of Pressurized Water Reactor (PWR) Head Penetrations, Revision 3. The inspectors observed that the examination was done using this procedure. The inspectors verified by direct observation and discussions with examination personnel that the approved acceptance criteria for lower head leakage were applied in accordance with the procedures.

Verification that the licensee was able to identify, disposition, and resolve deficiencies

The licensee's examination plan included a VT-2 examination using a remote crawler with attached video cameras in the front and rear. In addition, the examination used the resolution level of a VT-1. The licensee recorded all examinations of the nozzles. Any suspected leakage observed by the visual examination was noted and reviewed by materials engineers. The inspectors verified that the examination results for each nozzle were individually documented.

Verification that the licensee was capable of identifying the pressure boundary leakage as described in the bulletin or RPV lower head corrosion

The inspectors visually observed the Unit 2 lower head during the licensee's examination; observed the licensee conduct the examination; discussed the examination with the licensee examiners prior to, during, and following the examination; and verified the qualifications of the licensee examination personnel. The inspectors concluded that the licensee's visual examination was adequate to identify potential pressure boundary leakage lower head corrosion.

Evaluate ability for small boron deposits, as described in the bulletin, to be identified and characterized

The licensee examined the lower head with a remote crawler equipped with cameras to allow examination of each nozzle. The licensee drove the crawler directly below each row of the head in two directions, up and back. This provided two opposing views of each nozzle so that each nozzle was examined 360° around its circumference. The cameras on the crawler allowed examiners to zoom in close enough to see the annular region on each nozzle. The inspectors noted that this method allowed the licensee to adequately identify and characterize any small boric acid deposits.

Determine how the visual examination was conducted (video camera or direct visual by examination personnel)

The examination was done using a remote crawler with video cameras attached in the front and rear and a third camera that could tilt and zoom directly overhead. The licensee removed peripheral portions of insulation surrounding the lower head and placed the crawler on top of the remaining flat insulation below the lower head. The crawler traversed this insulation, below the lower head and nozzles, and the licensee used the tilt and zoom camera to examine the nozzles overhead.

Verify that the visual examination covered 360° around the circumference of all nozzles

As noted above, the visual examination did cover 360° around the circumference of each nozzle.

Evaluate the physical condition of the lower head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)

The inspectors viewed the condition of the Unit 2 lower head via remote video and performed a direct observation of portions of the head. The head was clean. It was generally silver with a feint orangish discoloration on one side. The nozzles showed no evidence of boron leakage, no debris, no surface boron from outside sources, and no viewing obstructions. There was a dark stain on several instrument tubes approximately one to two inches below the head penetration. The licensee determined this was most likely residue from non-adhesive flagging tape that was not removed prior to original startup and had melted onto the nozzle surface.

Determine extent of material deficiencies (associated with the concerns identified in the bulletin) which were identified that required repair

The licensee found no deficiencies that needed repair.

Determine any significant items that could impede effective examinations

The inspectors observed no examples of significant items that could impede the visual examination process.

Verify that the licensee performed appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components above the lower head

The licensee found minimal evidence on the Unit 2 lower head of boric acid leaks from pressure retaining components above the lower head.

Determine if the licensee was planning to clean the lower head

The licensee had plans to clean any boron deposits found during the examination. Because none were found, the Unit 2 lower head was not cleaned.

Document the licensee’s conclusions and rationale regarding the origin of any deposits present

As noted above, the licensee identified a dark stain on 25 of the 58 instrument tubes approximately one to two inches below the head penetration. The licensee performed a swipe test and residual scrapings in an attempt to sample the stain. The tests revealed the presence of some boron which the licensee attributed to residue from leakage that occurred during a reactor cavity flood-up in the past. The tests also indicated the presence of some fluorides, chlorides, and sulfates; however, an accurate measurement of total halogens and sulfates could not be obtained due to difficulty obtaining enough sample quantity. The licensee considered the amounts present to be low enough not to be a concern for stress corrosion cracking. Based on discussions with site personnel involved in site construction, the licensee determined the stain was most likely residue from non-adhesive flagging tape that was not removed prior to original startup and had melted onto the nozzle surface. The licensee documented these deposits and conclusions in PER 03-016523-000.

.2 NRC TI 2515/153, Reactor Containment Sump Blockage (NRC Bulletin 2003-01)

a. Inspection Scope

The inspectors evaluated licensee compensatory measures in response to NRC Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors (PWRs)," to determine whether they were effectively implemented in Units 1 and 2. Specifically, the inspectors reviewed the licensee response to the bulletin, dated August 8, 2003, and verified implementation, planning, and scheduling of the interim compensatory actions identified in the response, as indicated. The inspectors interviewed operators, reviewed training records, procedures, documentation of containment inspections, and foreign material control activities to the extent that these were included in the licensee response. The inspectors also reviewed reactor containment sump inspection and condition assessments. Documents reviewed are listed in the attachment.

b. Findings and Observations

No findings of significance were identified. As directed by the reporting requirements of TI 2515/153 and requested in discussions with the NRC Office of Nuclear Reactor Regulation (NRR), the following observations were included:

Containment walkdown to quantify potential debris sources

The inspectors observed that the wording used in the licensee's response to Bulletin 2003-01 described the completed walkdown of Unit 1 and the committed walkdown of Unit 2 as the same. In both instances, the licensee referred to the performance of "...a containment walkdown utilizing the guidelines of NEI 02-01." However, the walkdown done on Unit 1 was different from that done on Unit 2. The Unit 2 walkdown was performed using procedure TVA/SQN-CWD-Proc-01, Containment Walkdown Procedure for Potential Sump Screen Debris Sources, as described in contract document CWA-WEST-SQN-2003-0089, Sequoyah Nuclear Plant Unit 2 - NSSS Outage and Other Support Services, TVA Contract 00002695 (Reference 99NAN-251787-000), Walkdown of Containment for GSI-191 Concerns, Westinghouse Reference RFCO-12338, dated October 9, 2003. These, or similar documents, were not used to conduct the walkdown of Unit 1 nor did the Unit 1 walkdown quantify potential debris sources. From this the inspectors determined that, while the Unit 1 walkdown may have utilized the guidelines of NEI 02-01 as stated, it did not satisfy the intent nor specific guidance in NEI 02-01. The licensee had previously initiated PER 03-010154-000 in July 2003, to track licensee response to NRC Bulletin 2003-01 and has planned corrective actions to perform another walkdown of the Unit 1 containment in the fall of 2004 utilizing the guidelines in NEI 02-01. The licensee also initiated PER 04-000022-000 on these differences.

The licensee indicated that the Unit 2 containment walkdown quantified potential debris sources. However, the final results of the walkdown would not be available until March 2004. This TI will remain open pending completion of the inspection objectives.

During the Unit 2 walkdown, the licensee identified use of Cera Fiber, a fire retardant material, in electrical junction boxes inside containment. The inspectors noted that the licensee response to Bulletin 2003-01 had indicated that fire retardant material was not used inside containment. Upon questioning, the licensee entered the discovery into PER 03-018512-000.

Check for gaps in the sumps' screened flowpath and for major obstructions in containment upstream sumps

The inspectors directly observed walkdown activities associated with inspection of the emergency containment sump and refueling canal 14-inch drains. In addition, the inspectors reviewed procedures 0-SI-OPS-000-187.0, Containment Inspection, Revision 23; 0-SI-OPS-000-020.0, Containment Refueling Canal Drains, Revision 3, and 0-SI-SIN-063-009.0, Containment Sump Inspection, Revision 1, and observed portions of the surveillance implementation. No gaps were identified in the sump's screened flowpath and no major obstructions were identified in the refueling canal drains or the emergency sump.

Advanced Preparations to Expedite Sump-related Modifications

The licensee indicated that there were no pending advanced preparations to expedite the performance of sump-related modifications as no sump-related modifications had been identified. The inspectors identified and reviewed one plant modification, DCN D21426, that replaced existing Nukon fiberglass insulation installed on the Unit 2 pressurizer safety valve loop seal piping with mirror reflective metal insulation to address recirculation performance. The review is further documented in section 1R17 of this report.

Action Plan to Refill Refueling Water Storage Tank

At the request of the NRC Office of NRR, the inspectors reviewed guidance for refilling the refueling water storage tank (RWST). The inspectors determined, based on a review of revised licensee procedures and discussion with licensee procedure writers, that the procedures did not specify consideration nor initiation of RWST refill activities prior to indications of recirculation sump degradation.

4OA6 Meetings, including Exit

Exit Meeting Summary

On January 7, 2004, the resident inspectors presented the inspection results to Mr. Rick Purcell and other members of his staff, who acknowledged the findings.

The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. Some proprietary information was reviewed, however, none was entered into this report.

4OA7 Licensee-Identified Violations

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements which met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV:

TS 6.8.1.a requires that written procedures be implemented covering the activities in RG 1.33, Revision 2, Appendix A. Paragraph 9.a. of Appendix A recommends that maintenance that can affect the performance of safety-related equipment be properly preplanned and performed in accordance with written procedures appropriate to the circumstances. Contrary to the above and to Procedure 0-TI-PDM-000-057.6, Lubrication, Revision 18, the licensee, on three occasions, added the wrong lubricant to safety-related equipment. This violation is of very low significance because operability was not affected on any occasion. On October 25, 2002, the wrong lubricant was added to ERCW Strainer A2A-A without a work procedure appropriate to the circumstance. This issue is documented in PER 02-013505-000 and PER 02-013637-000. On January 21, 2003, the wrong lubricant was installed in TDAFW Pump 2A-S, because installers did not follow the WO. This issue is documented in PER 03-011298-000. On March 19, 2003, an estimated 55 gallons of the wrong lubricant were added to EDG 1A-A Engine 2 following a 24-hour run, again because installers did not follow the WO. This issue is documented in PER 03-009567-000.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION
KEY POINTS OF CONTACT

Licensee personnel:

J. Bajraszewski, Licensing Engineer
D. Clift, Maintenance and Modifications Manager
H. Cothran, Steam Generator Manager
J. Gates, Business & Work Performance Manager
M. Gillman, Operations Manager
C. Kent, Radcon/Chemistry Manager
D. Koehl, Engineering and Site Support Manager
D. Kulisek, Plant Manager
D. Lundy, Site Engineering Manager
R. Purcell, Site Vice President
R. Rogers, Design Manager
P. Salas, Licensing and Industry Affairs Manager
J. Smith, Site Licensing Supervisor
D. Thompson, Security Manager

NRC personnel:

R. Bernard, Region II, Senior Reactor Analyst
M. Marshall, Project Manager, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000328/2003006-01	NCV	Failure to Implement Timely and Appropriate Fire Protection Compensatory Measures (Section 1R05).
05000328/2003006-02	NCV	Inadequate Inservice Inspection Resulted in Failure to Correctly Identify a Gap in Pipe Support 2-CVCH-105 (Section 1R08).
05000327, 328/2003006-03	NCV	Failure to Maintain Qualification Records for Licensed Operator Reactivation (Section 1R11).
05000327, 328/2003006-04	NCV	Failure to Comply with Configuration Control Procedures (Section 1R13).
05000327/2003006-05	NCV	Failure to Manage the Risk from Proposed Maintenance Activities (Section 1R13).

05000328/2003006-06	NCV	Failure to Comply with Procedure for Draining to Mid-loop (Section 1R20).
05000327/2003006-07	FIN	Failure to Maintain Configuration Control of Turbine Oil Valves Resulted in Reactor Trip (Section 4OA3.1).
05000328/2003006-08	NCV	Inadequate Procedure for Protecting RWST Level Instruments (Section 4OA3.3).

<u>Closed</u>

05000328/2002001-00	LER	Inadvertent Auxiliary Feedwater System Actuation Signal (Section 4OA3.2)
05000328/2003002-00	LER	Limiting Condition for Operation 3.0.3 Was Entered when Two Refueling Water Storage Tank Level Transmitters Failed During Cold Weather Conditions (Section 4OA3.3)
05000328/2003003-00	LER	Excessive Leakage of a Containment Purge System Containment Isolation Valve (Section 4OA3.4)
05000328/2003003-02	URI	Frozen RWST Instrumentation (NOED 03-6-001) (Section 4OA3.3)
05000328/2003003-03	URI	Containment Purge Valve Leakage (NOED 03-02-004) (Section 4OA3.4)

<u>Discussed</u>

05000327/2003001-00	LER	Manual Reactor Trip as a Result of a Main Generator Trip and Loss of Load (Section 4OA3.1)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

0-PI-OPS-000-006.0, Freeze Protection, Revisions 31 and 34
0-PI-MIN-000-706.0, Freeze Protection Insulation Inspection, Revision 5
1-PI-EFT-234-706.0, Freeze Protection Heat Trace Functional Test, Revision 22
2-PI-EFT-234-706.0, Freeze Protection Heat Trace Functional Test, Revision 16
M&AI-27, Freeze Protection, Revision 8
WO 03-001624-000, Inspect Insulation, Remove Insulation, Inspect Heat Trace Installation of All ERCW Pump Station Heat Traced Piping
PER 03-000924-000, On January 24, 2003, ERCW Heat Trace Circuits Low Temperature Alarms Occurred on Several Circuits
Clearance 0-234-0420A-W/W, Tag-out 0-TO-2003-0006
G-82, Installation, Modification, and Maintenance of Insulation, Revision 2

Section 1R04: Equipment Alignment

Unit 1 RHR Auxiliary Building Drawing showing Component Elevations, Dated February 28, 2002, Revision 1
1, 2-47W810-1, Units 1 & 2 Flow Diagram Residual Heat Removal System, Revision 43
1-47W811-1, Unit 1 Flow Diagram Safety Injection System, Revision 59
PER 03-012338-000, During performance of 1-SI-OPS-074-128.0, Unit 1 RHR Discharge Piping Vent, AUO's noted that section 6.2 required 9 gallons of water to be vented from 1-VLV-63-413 before all air was removed.
RHR and other Gas Accumulation Trend Data from July 1998 to November 2003
System 74 RHR Reference Guide
Reports of open System 74 PERs and of all PERs with between August 2002 and September 2003 containing key word "RHR"
EASI Report of Open DCNs
EASI Report of Open Work Orders and Preventive Maintenance for System 74
Unit 1 RHR System 74 Health Status Report for 3rd Quarter, FY03

Section 1R05: Fire Protection

SPP-10.9, Control of Fire Protection Impairments, Revision 2
SPP-10.10, Control of Transient Combustibles, Revision 2

Section 1R06: Flood Protection Measures

AOP-M.01, Loss of Essential Raw Cooling Water
AOP-N.03, Flooding, Revision 19
ARP 1-AR-M15-B, Miscellaneous 1-XA-55-15B, Revision 22
0-PI-IFT-040-001.0, Functional Test of Auxiliary and Reactor Building Flood Alarms, Revision 3
2-PI-IFT-040-001.0, Functional Test of Auxiliary and Reactor Buildings Flood Alarms, Revision 3

Section 1R08: Inservice Inspection Activities

Procedures and Standards
TVAN Standard Programs and Processes SPP-9.1, Rev. 5, ASME Section XI
Sequoyah Surveillance Instruction 0-SI-DXI-000-114.2, Rev. 18, ASME Section XI ISI/NDE Program Unit 1 and Unit 2
Nondestructive Examination Procedure N-UT-64, Rev. 6, General Procedure for the Ultrasonic

Examination of Austenitic Pipe Welds

Nondestructive Examination Procedure N-PT-9, Rev. 25, Liquid Penetrant Examination of ASME and ANSI Code Components and Welds

Nondestructive Examination Procedure N-VT-1, Rev. 34, Visual Examination Procedure for ASME Section XI Preservice and Inservice

TVA General Engineering Specification G-43, Rev. 13, Installation, Modification, and Maintenance of Pipe Supports and Pipe Rupture Mitigative Devices

Documents Reviewed

Ultrasonic Calibration/Examination Summary and Resolution Sheet Report No. R-6553 for Weld No. RC-35 on November 19, 2003 for ISI Drawing ISI-0008-C-01, 14" Diameter Stainless Steel Pipe

Ultrasonic Calibration/Examination Report for FAC UT Data Evaluation Form Report No. R-6562 for Component 203BP171 and 2433R026 on November 20, 2003 for Pipe Thickness for 16" Diameter pipe and 6" x 4" Reducer for Feed Water Line

Record of Liquid Penetrant Exam Report No. R-6555 on November 18, 2003 for Pipe Attached Lug Welds for Support 2-SIH-080IA, Safety Injection System

Record of Liquid Penetrant Exam Report No. R-6554 on November 20, 2003 for Pipe Attached Welds for Support 2-SIH-103IA, Safety Injection System

TVA Record of Visual Examination Report Nos. R-6556 to R-6561 on November 19, 2003 for Pipe Supports 2-CVCH-043, -075, -046, -049, -105, and -103, of Chemical Volume and Cooling System

TVA Record of Visual Examination Reports on November 17 and 18, 2003 for Pipe Supports 2-SIH-103 and -80, of Safety Injection System

Drawing 2-47K406-121, Rev. 0, N2-62-13R Isometric, Static, Thermal, and Seismic Analysis Of CVCS Piping

Drawing 2-47W809-1, Rev. 66, Flow Diagram Chemical & Volume Control System

Drawing CCD-2-2-H34-0105-01, Rev. 0, of Mechanical Chemical & Volume Control System Pipe Supports for Support No. 2-CVCH-105

Sequoyah Problem Evaluation Report (PER) Nos. 03-017054-000, 03-017128-000, 03-017140-000, and 03-017141-000

Sequoyah Unit 2 Notification of Indication Form (NOI) No. 2-SQ-355 for Examination Report No. R-6404, Dated April 27, 2002

TVA Relief Request submitted to NRC on October 15, 2003 for Sequoyah Units 1 and 2 for NRC Regulatory Issue Summary (RIS) 2003-01, Examination of Dissimilar Metal Welds, Supplement 10 to Appendix VIII of Section XI of the ASME Code, Dated January 21, 2003

Letter from J. C. Goulart, OPS 3D-SQN to F. R. Scalise, OPS 3D-SQN on July 22, 1996, Subject: Clearances of Supports, Guides, and Stops

Work Order Nos. 01-001446-000 and 00-011528-000

<u>Section 1R11: Licensed Operator Requalification</u>

SQN Simulator Transient Test Raw Data

Simulator Deficiency Report

SQN-TRN-03-007, Self Assessment Report

TRN 11.4, Continuing Training For Licensed Personnel

TRN-11.9, Simulator Exercise Guide Development and Revision

TRN 11.10, Annual Requalificaiton Examination Development and Implementation

TRN -11.12, Job Performance Measures Development Administration and Evaluation Manual

TRN-11.14, TVA Operator Licensing examination Security Program

TRN-12, Simulator Regulatory requirements

ODM-1, Conduct of Operations
Operation Logs
CAD Records

Section 1R12: Maintenance Effectiveness

PER 03-011298-000, Oil of incorrect viscosity identified in TDAFW Pump 2A-S
PER 03-009567-000, Oil of incorrect viscosity found in DG 1A-A Engine 2
0-TI-PDM-000-057.6, Lubrication, Revisions 18, 19
WO 03-001684-000, Following 24-hr D/G run, the 1A-A Engine 2 oil level is 1 inch below the 4-inch mark
WO 02-011261-000, Inspect, add oil, packing, and housing drains for TDAFW pump 2A-S
WO 03-009579-000, Drain oil from EDG 1A2 engine; replace with new Mobilguard 450NC
Attachment 4, AFW-Flood Mode Fire Pumps - System 26, to TI-4, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting - 10 CFR 50.65, Revision 15
PER 02-013504-000, Oil was added to the A2A-A ERCW strainer without appropriate procedure or documentation
WO 02-013503-000, Sampled A2A-A ERCW strainer oil for analysis
WO 02-011284-000, Inspected A2A-A ERCW strainer and replaced oil
PER 02-013637-000, Oil of incorrect viscosity found in A2A-A ERCW strainer
WO 02-011227-000, Sample oil in TDAFW Pump Turbine 2A-S
G-29 Part B, Materials and Procurement, Section 1 Materials Handling and Processing Specifications, Revision 39; SPEC: P.S.4.M.1.5(R3) - Classification, Procurement, Receipt and Use of Lubricants
SPP-10.3, Verification Program, Revision 0
MMDP-1, Maintenance Management System, Revision 5
SPP-4.1, Procurement of Material, Labor and Services, Revision 11
1,2-47W850-24, Mechanical Flow Diagram - Fire Protection, Revision 18

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

O&SSDM 4.8, Critical Evolution Meeting, Revision 0
Regulatory Guide 1.182, Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants
NUMARC 93-01, Nuclear Energy Institute Industry Guideline for Monitoring The Effectiveness of Maintenance at Nuclear Power Plants, Revision 2
SPP-10.1, System Status Control, Revision 2
EWR No. 03-NSS-068-006, Unit 2 Reactor Coolant System Pressurizer Vapor Space Leak Hunt, Approved February 24, 2003
EWR No. 03-NSS-068-0007, Unit 1 Reactor Coolant System Pressurizer Relief Tank Inleakage, Approved February 25, 2003
AOP-R.05, Abnormal Operating Procedures - RCS Leak and Leak Source Identification, Revision 8
TI-4, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting - 10 CFR 50.65, Revision 15
ODM-1.0, Conduct of Operations, Appendix D - Procedure Usage, Revision 0
OPDP-1, Conduct of Operations, Revision 2
E-mail, from Jay Walling dated February 28, 2003, reporting that sentinel had been updated as of February 28, 2003, for workweeks 2003/02/25, 2003/03/03, and 2003/03/10, due to the addition of the blocked Unit 2 PORVs.
NEDP-20, Conduct of The Engineering Organization, Revision 3
PER 03-001408-000, Unit 1 pressurizer PORVs 1-68-340A and -334A leakoff temperature

indicator indicated potential PORV seepage.
PER 03-002050-000, PORV block valves for both units were closed per EWRs with no risk assessment.
Maintenance Rule System 068 U1 and U2 Monthly Reports for January - April, 2003
Operations Required Reading 0RR03015, PZR PORV Block Valves Closed Without Risk Assessment (PER 03-002050-000), dated 4/30/03
ARP 2-AR-M-5, Ventilation 2-XA-55-5C, Revision 11
ARP 2-AR-M5-A, Reactor Coolant - STM - FW 2-XA-55-5A, Revision 16
PEDS Computer Trend of Unit 1 and Unit 2 pressurizer block valves 1-FCV-68-333, -332, 2-FCV-68-333, -332 positions during the 35-day period around March 2, 2003
SPP-2.2, Administration of Site Technical Procedures, Revision 10
PER 03-016967-000, NRC Identified deficiencies in outage risk management process
PER 04-770254-000, Evaluation of the Integration of the Clearance Process and the Risk Assessment Process.
PER 03-017088-000, 1B CCP Tagged out when the Risk Review of the Schedule Intended for the Pump to Remain Available.
PER 03-017124-000, The duty work week manager failed to update the PSA color in the POD package on 11/19/03.

Section 1R16: Operator Work-Arounds
Report of open "GL 91-18" PERs, dated November 16, 2003
ODM-3.7, Operator Work-Around Program, Revision 8
OPDP-4, Annunciator Disablement, Revision 1S1
0-PI-OPS-301.0, Plant Computer Disablement, Revision 21

Section 1R20: Refueling and Other Outage Activities
0-GO-7, Unit Shutdown from Hot Standby to Cold Shutdown, Revision 31
0-GO-13, Reactor Coolant System Drain and Fill Operations, Revision 42
0-GO-15, Containment Closure Control, Revision 16
N-UT-72, Measuring Fluid Levels on Number 4 Hot Leg, Revision 2
O&SSDM 4.0, Operational Defense-in-Depth Assessment, Revision 10
SPP-6.5, Foreign Material Control, Revision 7S1
2-PI-IXX-068-005.0, Installation and Removal of the Mansell Level Monitoring System During Refueling Outages, Revision 6
0-PI-OPS-068-673.W, Weekly Requirements For Modes 5 and 6 Operations, Revision 10

0-TI-XSS-000-016.0, Breaching The Shield Building, ABSCE, or Control Room Boundaries, Revision 17
0-PI-ICC-068-005.0, Calibration of The Mansell Level Monitoring System Transducers, Revision 1
2-PI-OPS-068-673.0, Daily Requirements for Reduced Inventory/Midloop Operations, Revision 8
TVA Responses to Generic Letter 88-17, dated January 6, February 2, and August 25, 1989
NRC Generic Letter 88-17, Loss of Decay Heat Removal
0-TI-OXX-068-001.0, Reactor Coolant System Hot Leg Vents and Generic Letter 88-17 Issues, Revision 13
Tagout 2-TO-2003-0005 / Clearance 2-67-1222-RFO, ERCW B Train ESF Header MIC Repair
Tagout 2-TO-2003-0005 / Clearance 2-67-1396-RFO, Repair pinhole leak in ERCW return piping from Train B MCR and EBR chillers
MMDP-12, Lockout/Tagout, Revision 1

PER 03-016967-000, NRC Identified deficiencies in outage risk management process

Section 1R23: Temporary Plant Modifications

SPP-9.3, Plant Modifications and Engineering Change Control, Revision 9
2-SO-2/3-1, Condensate and Feedwater System, Revision 45
EA-2-2, Establishing Secondary Heat Sink Using Main Feedwater or Condensate System, Revision 5
FR-H.1, Loss of Secondary Heat Sink, Revision 15
UFSAR 10.4.7.1, Condensate - Main Feedwater System
1,2-47W851-1, Mechanical Flow Diagram - Floor & Equipment Drains, Revision 24
1,2-47W814-2, Flow Diagram - Ice Condenser System, Revision 21

Section 4OA1: Performance Indicator Verification

LER 50-327/2002-002-00, Automatic Reactor Trip Resulting from a Failure of a Breaker Causing an Undervoltage Condition on Two Reactor Coolant Pumps and Failure to Perform a Technical Specification-Required Action
LER 50-328/2002-003-00, Automatic Reactor Trip Resulting from a Generator Stator Cooling Water High Temperature Caused by a Raw Cooling Water Valve Failure
LER 50-328/2002-004-00, Reactor Trip Resulting from the Loss of a Reactor Coolant Pump
LER 50-328/2003-001-00, Reactor Trip Signal as a Result of a Low-Low Steam Generator Level
LER 50-328/2003-002-00, Limiting Condition for Operation 3.0.3 Was Entered when Two Refueling Water Storage Tank Level Transmitters Failed during Cold Weather Conditions
LER 50-328/2003-003-00, Excessive Leakage of a Containment Purge System Containment Isolation Valves
LER 50-328/2003-004-00, Reactor Trip Resulting from a Neutral Over-Current Condition on the 2B Hotwell Pump and a Failure to Perform a Technical Specification-Required Action
LER 50-328/2003-005-00, Reactor Trip Resulting from a Spurious Turbine Vibration Trip Signal
LER 50-328/2003-006-00, Failure to Meet Technical Specification Limiting Condition for Operation Action Time for the Component Cooling System

Section 4OA2: Problem Identification and Resolution

PER 01-005036-000, Valve 2-FCV-70-156 Trip on Thermal Overload while being throttled to an as-found position
PER 01-009247-000, Valve 0-FCV-070-0198-B Thermal Overloads Tripped Apparently Due to High Running Loads
PER 01-010430-000, Valve 0-FCV-070-0198-B Thermal Overloads Tripped Apparently due to High Running Loads
PER 03-011298-000, Oil of incorrect viscosity identified in TDAFW Pump 2A-S
PER 03-009567-000, Oil of incorrect viscosity found in DG 1A-A Engine 2
0-TI-PDM-000-057.6, Lubrication, Revisions 18, 19
WO 03-001684-000, Following 24-hr D/G run, the 1A-A Engine 2 oil level is 1 inch below the 4-inch mark
WO 02-011261-000, Inspect, add oil, packing, and housing drains for TDAFW pump 2A-S
WO 03-009579-000, Drain oil from EDG 1A2 engine; replace with new Mobilguard 450NC
PER 02-013504-000, Oil was added to the A2A-A ERCW strainer without appropriate procedure or documentation
WO 02-013503-000, Sampled A2A-A ERCW strainer oil for analysis
WO 02-011284-000, Inspected A2A-A ERCW strainer and replaced oil

PER 02-013637-000, Oil of incorrect viscosity found in A2A-A ERCW strainer
WO 02-011227-000, Sample oil in TDAFW Pump Turbine 2A-S
PER 00-001824-000, Wrong Oil in CCP 1AA
PER 00-000241-000, Wrong Oil in SIP 1BB
PER 02-014108-000, Review of Degraded / Non-conforming condition (91-18) PERs
SPP-10.10, Control of Transient Combustibles, Revision 2
SPP-10.2, Clearance Program, Revision 5
MMDP-12, Lockout / Tagout, Revision 1
TI-4, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting - 10 CFR 50.65, Revision 15
0-TI-PDM-000-057.6, Lubrication, Revisions 18 and 19
SPP-6.1, Work Order Process Initiation, Revision 3
G29 Part B - Materials and Procurement, Section 1 - Materials Handling and Processing Specifications, Revision 39
MMDP-1, Maintenance Management System, Revision 5
SPP-4.1, Procurement of Material, Labor and Services, Revision 11
PER 03-006959-000, Valve 1-21-581 leaking through. A cracked disc was found.
PER 03-000715-000, Channel I and III of Unit 2 Wide Range RWST Level Instruments Failed High
PER 03-000783-000, Evaluate Operations Freeze Protection Plan
PER 03-002446-000, Common Cause Evaluation for Freeze Protection Issues of January 24, 2003
M&AI-27, Freeze Protection, Revision 8
0-PI-MIN-000-706.0, Freeze Protection Insulation Inspection, Revisions 4 & 5
2-PI-EFT-234-706.0, Freeze Protection Heat Trace Functional Test, Revisions 15 & 16
1-PI-EFT-234-706.0, Freeze Protection Heat Trace Functional Test, Revision 23
0-PI-OPS-000-006.0, Freeze Protection, Revision 34

<u>Section 4OA3: Event Follow-up</u>

PER 02-004059-000, Inadvertent Auxiliary Feedwater System Actuation Signal
Operations Required Reading 02017, Unexpected FWI Following Shutdown for U2C11 RFO
0-GO-6, Power Reduction from 30% Reactor Power to Hot Standby, Revision 19
Simulator Problem Report 3411
NRC Event Notification 38854, ESF Actuation Resulting in Automatic Repositioning of AFW Valves
PER 03-011940-000, Unit 1 Generator Trip While Performing Turbine Oil Trip Tests
1,2-47W807-2, Flow Diagram, EHC & Lube Oil Systems, Revision 10
0-TI-QXX-000-001.0, Event Critique, Post Trip Report, and Equipment Root Cause

<u>Section 4OA5: Other Activities</u>

Draft Regulatory Guide 1107, “Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident,” dated February 2003 (accession number ML030420318).
Los Alamos National Laboratory Technical Report LA-UR-02-7562, "The Impact of Recovery From Debris-Induced Loss of ECCS Recirculation on PWR Core Damage Frequency," dated February 2003 (accession number ML030690174).
NUREG/CR-6808, “Knowledge Base for the Effect of Debris on Pressurized Water Reactor Emergency Core Cooling Sump Performance,” dated February 2003 (accession numbers ML030780733 and ML030920540).
NEI 02-01, Revision 1, “Condition Assessment Guidelines: Debris Sources Inside PWR Containments,” dated September 2002 (accession number ML030420318).

Generic Letter 98-04, “ Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment.”
NRC Staff Responses to Industry Pre-Meeting Questions and Comments on Bulletin 2003-01 Provided in Support of June 30, 2003 NRC Public Meeting, June 30, 2003 (accession number ML031810371).
Revised NRC Staff Responses to Three Industry Questions on Bulletin 2003-01 Submitted Prior to the June 30, 2003, Public Meeting, August 7, 2003 (accession number ML032180011).
Operations Department Standing Order 03-014, Procedure Revisions Related to Containment Sump Blockage, Dated July 29, 2003
ES-1.3, Transfer to RHR Containment Sump, Revision 11
EA-63-8, Monitoring for Containment Sump Blockage, Revision 0
EPIP-6, Activation and Operation of the TSC, Revision 38
Sequoyah Nuclear Plant 60-Day Response to NRC Bulletin 2003-01, dated August 8, 2003
PER 03-016181-000, Debris Found Inside Polar Crane Wall during Mode 3 Walkdown
PER 03-008852-000, Wooden Blocks Wedged around S/G Blowdown Line and Fire Extinguishers in Raceway
PER 03-010154-000, Response to NRC Bulletin 2003-01
PER 02-005466-000, Nukon Insulation in Locations not Identified by Drawing 1,2-47W813-1E
PER 03-018003-000, Debris in Unit 2 Ice Bed during Cycle 12 Servicing and Maintenance.
PER 03-018512-000, Fire Retardant Material Found Inside Unit 2 Containment when Response to NRC Bulletin 2003-01 Said Otherwise
PER 02-003942-000, Missing mirror insulation on the Unit 2 letdown isolation valves.
PER 02-014108-000, Nukon insulation in locations which were not identified by insulation drawing 1,2-47W813-1E
PER 03-016609-000, Insulation Material on Steamline Inside the Unit 2, Loop 1, SG Compartment not Specified on Drawing
PER 03-016617-000, Grey Duct Tape in Unit 2 Containment inside Polar Crane Wall
Project Request Form - TRC # 334, Containment ECCS Sump, SQN 1 & 2; WBN 1
TVA/SQN-CWD-Proc-01, Containment Walkdown Procedure for Potential Sump Screen Debris Sources, Revision 0
Procurement Request SM-1827, Emergency Core Cooling System Sump Walkdown - NRC Bulletin 2003-01, Revision 00
WCAP-11534, Evaluation of Containment Coatings for Sequoyah Unit 2, September 15, 1987 (Westinghouse Proprietary Class 2)
DCN D21426, Replace existing Nukon fiberglass insulation installed on the Pressurizer Safety Valve Loop Seal piping with Mirror reflective metal insulation, Revision A
EPIP-6, Activation and Operation of the Technical Support Center, Revision 38
ES-1.3, Transfer to RHR Containment Sump, Revision 11
EA-63-2, Refilling the RWST, Revision 2
EA-63-8, Monitoring for Containment Sump Blockage, Revision 0
ECA-1.1, Loss of RHR Sump Recirculation, Revision 10
EPM-3-ECA-1.1, Basis Document for ECA-1.1 Loss of RHR Sump Recirculation, Revision 3
0-SI-OPS-000-187.0, Containment Inspection, Revision 23
0-SI-OPS-000-011.0, Containment Access Control During Modes 1-4, Revision 14
0-TI-DXX-000-010.0, Protective Coatings Program For Coating Service Level I and II and Corrosive Environmental Applications, Revision 0
0-TI-SXX-061-001.0, Ice Condenser Loose Debris Listing, Revision 4
0-SI-MIN-061-107.0, Ice Condenser Floor Drains, Revision 0

0-SI-OPS-000-020.0, Containment Refueling Canal Drains, Revision 3
0-SI-SIN-063-009.0, Containment Sump Inspection, Revision 1
0-SI-SXI-000-200.0, ASME Section XI Inservice Pressure Test Scheduling and Tracking, Revision 7
0-SI-SXI-000-201.0, ASME Section XI Inservice Pressure Test, Revision 14
0-SI-SXX-061-001.0, Ice Condenser Loose Debris Evaluation, Revision 0
Operations Department Standing Order 03-014, Procedure Revisions Related to Containment Sump Blockage, Approved 7/29/03, Expiration Date 09/01/03
OPL273C0309, Emergency Operating Procedures Revision 1C Training
PER 03-016523-000, Residual Deposits on In-core Tubing
TVA Thirty Day Response to NRC Bulletin 2003-02, dated September 22, 2003
N-VT-17, Visual Examination for Leakage of PWR Reactor Head Penetrations, Revision 3
WO 03-001060-000, Inspection of Unit 2 Reactor Vessel Lower Head